Non-Modeling Approaches: Use of Historical Generation and Emissions Data

TSD – State Plan Considerations

Prepared for US EPA

March 12, 2014

AUTHORS

Jeremy Fisher, PhD

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

Non-Modeling Approaches: Use of Historical Generation and Emissions Data

Typical uses

Organizations use non-modeling approaches for a variety of different reasons; to estimate future emissions inventories for state and regional air quality modeling, [1] to estimate the impact of load reduction measures (EE and RE) on individual EGU fossil emissions[2] and/or estimate regional emissions rates.[3] Because these algorithms are based on generally publicly available data,[4] and do not rely on economic data or proprietary information regarding individual EGU, they provide a low-cost, simple, and often transparent framework for estimating how EGU will respond to changes conditions. Some of these algorithms are designed to be operated by non-expert users, while others are made available for interested parties.

Features

Non-modeling approaches approximate future emissions and generation from existing and new fossil generators under different growth, retrofit and or load reduction requirements. These mechanisms do not simulate economic dispatch, but could use demand growth rates and electricity production trends from other energy modeling forecasts as an input assumption.[5] The algorithms in this approach assumes that power plant behaviors generally follow simple rules, and in the absence of significant shifts in commodity prices, can be expected to behave similarly in the future as today. Several features held in common amongst these methods are that they (a) generally build on historic generation and emissions output from individual EGU, (b) are insensitive to fuel and emissions price forecasts, (c) do not solve for optimal economic dispatch or new unit expansion, and (d) do not capture transmission constraints or limits. These algorithms generally divide the contiguous US[6] into regional power markets, following ISO boundaries, eGRID boundaries, NERC regional boundaries, or similar designations. These algorithms generally seek to examine how emissions from individual units could be expected to change operationally with additional or reduced hourly electrical demand. Some algorithms use the observed historic behavior of EGU to approximate future behavior, while others add additional steps of

[1] See, for example the ERTAC Load Growth Model http://www.ertac.us/index_egu.html.

[2] See EPA's AVERT (Avoided Emissions and Generation Tool) and

[3] See Flexibility Weighted Hourly Average Emissions Rate (FW-HAER) in http://nepis.epa.gov/Adobe/PDF/P1002UQO.pdf; see Time Matched Marginal (TMM) emissions tool, a proprietary algorithm used to estimate avoided emissions. D Jacobson and C High. 2010. U.S. Policy Action Necessary to Ensure Accurate Assessment of the Air Emission Reduction Benefits of Increased Use of Energy Efficiency and Renewable Energy Technologies. *Journal of Energy & Environmental Law.*

[4] Hourly emissions and generation data for all fossil EGU greater than 25 MW available from EPA's Clean Air Markets Division (CAMD) in Air Markets Program Data (AMPD).

[5] For example Energy Information Administration's Annual Energy Outlook 2013 growth rates and productions trends are available at: http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2013).pdf

[6] Hawaii and Alaska do not report hourly generation and emissions from individual EGU to EPA, and are thus generally excluded from these models.

differentiating units into fuel groups and unit types, with implicit differentiation of economic outcomes for these different groups. Some of these algorithms may contain subroutines to add new generation automatically to meet load requirements.

Application to emissions reduction approaches

These algorithms are best used to understand broad trends over a short period of time and under marginal system changes (i.e. relatively small changes in demand, commodity prices, or generation availability). Non-modeling approaches are generally designed to answer a limited range of questions, and may have narrow design specifications, implicit or explicitly described. For example, some tools are designed to review emissions inventories under an assumption of continuously growing load with predictable EGU behaviors, and are not designed to characterize load reductions. Because these algorithms are highly simplified representations of EGU behavior, they may not be appropriate to use for multiple simultaneous emissions reductions approaches. It may be argued that, due to their simplifying assumptions, non-modeling approaches are inappropriate to use when considering most emissions reductions approaches, as most of these approaches impact economic dispatch decisions and/or operational constraints. In addition, simplified approaches may not correctly capture geographic patterns (i.e. in-state versus out-of-state emissions reductions).

- EGU efficiency improvements and/or fuel switching: Non-modeling approaches capture only emissions rate changes due to efficiency improvements or fuel switching. Fuel switching and efficiency improvements fundamentally change variable costs for EGU, and consequently their position in loading order. Thus, dispatch behavior (and thus net emissions) of both the EGU under consideration and other EGU in the system will not be captured by non-modeling approaches.
- Re-dispatch of the EGU fleet: Non-modeling approaches do not consider economic dispatch, and thus are unlikely to be able to capture the impact of emissions markets on EGU dispatch, or likely unit or system-wide responses to specific EGU emissions limits.
- EE/RE Programs: Some of the non-modeling approaches characterized here are designed specifically to estimate how either individual units or a broader generation fleet would respond to changes in demand, assuming no change in economic forcing (i.e. commodity prices or emissions costs).

Discussion

Non-modeling approaches are highly simplified representations of the electric sector, designed to answer specific questions about EGU behavior from a specific forcing factor (often demand). As such, they are limited in their ability to capture changes driven by economics (i.e. fuel and emissions prices) or specific unit limitations (generation or emissions restrictions). These approaches may deviate from reasonable expectations when conditions change significantly, such as when demand is dramatically reduced, the fleet is restructured, or new transmission is constructed. These type of approaches should be benchmarked or characterized for likely or possible deviations from expected system behavior, and such characterizations require expert review. Algorithms open to review and scrutiny are more likely to be appropriately vetted and characterized.

The circumstances in which these algorithms may differ from realized outcomes should be made explicit. Many of these approaches are unable to capture economic considerations and would need to rely on information from other sources, energy modeling forecasts or extrapolate historical trends.[7]. For example, if natural gas prices rise dramatically, additional gas-fired generation is likely to be on the margin; algorithms that predict significant coal-fired emissions reductions from EE and RE based on current spreads may therefore over-predict emissions changes as gas (and not coal) generators reduce generation from reduced demand. In not capturing transmission constraints, these algorithms are generally insensitive to the location of EE or RE. If a modeled region has a "hard" boundary (i.e. represents a limited geographic extent), it may significantly mischaracterize emissions reductions from EE or RE implemented near the edge of the regional analysis.[8] Algorithms that add (or remove) EGU automatically may make intuitive, rather than economic decisions, and thus it is important to pay special attention to possible mischaracterize emissions changes on the build margin. Finally, significant changes in demand, new additions to transmission, and significant additions or retirements all change system dynamics; non-modeling approaches may not capture how these changes impact dispatch. These approaches are typically transparent, use publically available data and can be used by non-electricity model experts.

[7] Data may come from an energy office, utility commissions, academic organizations, Energy Information Administration, Regional Transmission Organizations, Environmental Protection Agency electric power sector modeling or utilities etc.

[8] Emissions reductions from EE and RE will tend to be spread over large geographic areas (see J Fisher, C James, et al., 2011.Emissions reductions from renewable energy and energy efficiency in California Air Quality Management Districts. Prepared for California Energy Commission. http://uc-ciee.org/downloads/CAEmissionsReductions.pdf). If an EE or RE program is implemented near an artificial boundary, some of the reductions that should be realized by EGU over the boundary's borders will not be captured by the algorithm.